

DIRECT TESTIMONY AND EXHIBIT

OF

BRIAN HORII

ON BEHALF OF THE

SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2019-2-E

IN RE: ANNUAL REVIEW OF BASE RATES FOR FUEL COSTS FOR

SOUTH CAROLINA ELECTRIC & GAS COMPANY

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Brian Horii. My business address is 44 Montgomery Street, San Francisco, California 94104. I am a Senior Partner with Energy and Environmental Economics, Inc. ("E3") and have been retained by the South Carolina Office of Regulatory Staff ("ORS") to assist in the analysis of South Carolina Electric & Gas Company's ("SCE&G" or "Company") avoided cost calculations, and review the Value of Distributed Energy Resource ("DER") methodology, in this Docket.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have over thirty (30) years of experience in the energy industry. My areas of expertise include avoided costs, utility ratemaking, cost-effectiveness evaluations, transmission and distribution planning, and distributed energy resources. Prior to joining E3 as a partner in 1993, I was a researcher in Pacific Gas and Electric Company's ("PG&E") Research & Development department and was a supervisor of electric rate design and revenue allocation. I have testified before commissions in California, British

Columbia, and Vermont, and have prepared testimonies and avoided cost studies for utilities in New York, New Jersey, Texas, Missouri, Wisconsin, Indiana, Alaska, Canada and China.

I received both a Bachelor of Science and Master of Science degree in Civil Engineering and Resource Planning from Stanford University. My full curricula vita is provided as Exhibit BKH-1.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA (“COMMISSION”)?

A. Yes, I previously testified before this Commission on behalf of ORS in Docket Nos. 2017-2-E and 2018-2-E.

Q. WHY WERE YOU RETAINED BY ORS IN THIS PROCEEDING?

A. ORS retained E3 to assist in reviewing SCE&G’s avoided cost calculations and other matters arising from Act 236 to:

- 1) Verify the Company is using the avoided cost methodology approved by the Commission;
- 2) Confirm the methodology meets the Public Utility Regulatory Policies Act of 1978 (“PURPA”) requirements;
- 3) Verify the avoided cost rates requested by SCE&G in this Docket are a reasonable result of the approved avoided cost methodology; and
- 4) Verify the Variable Integration Charge requested by SCE&G in this Docket is reasonable and quantified correctly.

ORS also retained E3 to conduct an analysis of SCE&G’s Value of DER calculation to:

- 1 1) Verify the Company populated each of the eleven (11) categories according to the
- 2 methodology established in Order No. 2015-194;
- 3 2) Confirm, for each category with a zero value, that the Company does not have sufficient
- 4 capability to accurately quantify those costs or benefits to the utility system; and
- 5 3) Verify, for each category with a value other than zero, that the value assigned is a result
- 6 of the Company's ability to accurately quantify those costs or benefits to the utility
- 7 system.

8 My prior work experience in this subject matter includes the following:

- 9 • Developed the methodology for calculating avoided costs used by the California Public
- 10 Utilities Commission for evaluation of DER since 2004;
- 11 • Developed the methodology for calculating avoided costs used by the California
- 12 Energy Commission for evaluation of building energy programs;
- 13 • Authored avoided cost studies for BC Hydro, Wisconsin Electric Power Company, and
- 14 PSI Energy;
- 15 • Provided review of, and corrections to, PG&E avoided cost models used in their general
- 16 electric rate case;
- 17 • Developed the integrated planning model used by Con Edison and Orange and
- 18 Rockland Utilities to determine least cost DER supply plans for their network systems;
- 19 • Developed the hourly generation dispatch model used by El Paso Electric Company to
- 20 evaluate the marginal cost impacts of their off-system sales and purchases;
- 21 • Produced publicly vetted tools used in California for the evaluation of energy efficiency
- 22 programs, distributed generation, demand response, and storage programs;

- Analyzed the cost impacts of electricity generation market restructuring in Alaska, Canada, and China; and
- Developed the “Public Tool” used by California stakeholders to evaluate Net Energy Metering (“NEM”) program revisions in California.

Q. PLEASE BRIEFLY DESCRIBE THE REQUIREMENTS OF PURPA AND HOW THEY RELATE TO THE PR-1 AND PR-2 RATE SCHEDULES PROPOSED BY THE COMPANY.

A. In 1978, as part of the National Energy Act, Congress passed PURPA. The policy was designed, among other things, to encourage conservation of electric energy, increase efficiency in use of facilities and resources by utilities, and produce more equitable retail rates for electric consumers.

To help accomplish PURPA goals, a special class of generating facilities called Qualifying Facilities (“QFs”) was established. QFs receive special rate and regulatory treatments, including the ability to sell capacity and energy to electric utilities. All electric utilities, regardless of ownership structure, must purchase energy and/or capacity from, interconnect to, and sell back-up power to a QF. This obligation is waived if the QF has non-discriminatory access to competitive wholesale energy and long-term capacity markets.

In SCE&G’s service territory, Small Power Producers and Cogenerators that are designated as QFs and have capacity less than or equal to 100 kilowatts (“kW”) are compensated under SCE&G’s Rate PR-1. Power purchased from QFs with capacity greater than 100 kW and less than or equal to 80 megawatts (“MW”) is compensated under

SCE&G's Rate PR-2. Rates PR-1 and PR-2 are updated annually in accordance with Commission Order No. 2018-322(A).

Q. PLEASE DESCRIBE THE METHODOLOGY SCE&G USED IN THIS FILING TO CALCULATE ITS AVOIDED ENERGY AND AVOIDED CAPACITY COSTS.

A. SCE&G calculates avoided energy costs using a methodology known as the Differential Revenue Requirement ("DRR"). This method calculates the revenue requirements associated with two (2) resource plan scenarios: a base case without the QF, and a change case with the QF. This methodological framework is one of the accepted methods for calculating PURPA avoided costs.

For the long-run avoided energy cost calculations, in both the base case and the change case, SCE&G uses PROSYM, a production cost model, to simulate the commitment of generating units to serve load on an hourly basis over a 15-year Integrated Resource Plan ("IRP") planning horizon. The base case is constructed by using load forecasts and supply side resources as described in the IRP. The change case modifies the base case load forecasts and supply side resources by modeling the addition of 100 MW of solar generation to measure the reduction in energy cost equal to the impact of adding 100 MW of solar to the SCE&G supply side resources. Finally, the avoided energy costs are levelized and adjusted for taxes and working capital.

SCE&G, as in Docket No. 2018-2-E, did not calculate a long-run avoided cost of capacity.

Q. IS THE METHOD USED BY SCE&G TO CALCULATE AVOIDED ENERGY COSTS CONSISTENT WITH THE METHODOLOGY APPROVED BY THE COMMISSION?

1 **A.** Yes. This is the same methodology used by SCE&G in Docket No. 2018-2-E and
2 approved by the Commission in Order No. 2018-322(A).

3 **Q. PLEASE DESCRIBE THE UPDATES MADE BY SCE&G TO THE AVOIDED**
4 **ENERGY COSTS.**

5 **A.** A review of the current and prior testimony and work papers shows that the
6 variance in avoided energy costs is primarily driven by the difference in fuel forecasts
7 between the 2018-2-E docket and the current docket. There appear to be no major changes
8 in network configurations or import/export assumptions. Other variables include slight
9 differences between the IRPs filed by SCE&G for 2018 and 2019, including differences in
10 near-term purchased power amounts and a slight change in long-term annual sales growth
11 (from 1.1% territorial sales growth annually to 0.9%). The 2019 IRP reflects some
12 differences in the mix of generation resources, such as including more utility scale solar,
13 but the scale of these differences is not likely to cause significant changes to which
14 generation resources are on the margin in the PROSYM model. Thus, changes in load and
15 components of electric supply are relatively slight and the difference in avoided energy
16 costs are primarily driven by the difference in fuel forecasts.

17 **Q. ARE THE UPDATES IN AVOIDED ENERGY COSTS A REASONABLE AND**
18 **CONSISTENT RESULT OF THE METHODOLOGY USED BY SCE&G?**

19 **A.** Yes. SCE&G applied the approved DRR methodology to calculate avoided energy
20 costs in a manner consistent with past filings of Rate PR-1 and Rate PR-2. I have reviewed
21 the fuel price forecasts SCE&G used in calculating the avoided energy cost for both the
22 2018 and 2019 fuel adjustment proceedings, and the forecast methodologies and values are
23 consistent with market knowledge available at the time of the forecasts. Given the minor

changes in loads and supply, it is reasonable that the avoided energy cost calculation is driven primarily by changes in fuel price forecasts.

Q. IN YOUR OPINION, IS THE METHOD USED BY SCE&G TO CALCULATE AVOIDED ENERGY COSTS APPROPRIATE?

A. Yes, it is appropriate for solar generators.

Q. WHAT DOES SCE&G PROPOSE FOR THEIR AVOIDED CAPACITY COSTS?

A. SCE&G has again proposed a value of zero for the avoided capacity costs for incremental solar projects for Rates PR-1 and PR-2 and in the value of DER.

Q. WHAT ARE SCE&G'S STATED REASONS FOR PROVIDING A ZERO VALUE FOR THEIR AVOIDED CAPACITY COSTS?

A. SCE&G asserts that the "need for capacity is driven by the winter season" and "because solar does not provide capacity during the winter period, the Company is unable to avoid any of its projected future capacity needs and, therefore, the avoided capacity cost of solar for these winter months is zero" (Neely, pp. 9-10).

Q. WHAT IS THE BASIS FOR SCE&G'S CONCLUSION THAT INCREMENTAL SOLAR PROVIDES NO CAPACITY VALUE IN THE WINTER SEASON?

A. Witness Lynch testifies that SCE&G forecasts winter peaks to be higher than summer peaks over the 15-year forecast period (Lynch, p. 8) and that solar only has the ability to reduce the winter peak in one out of the past five winters (Lynch, p. 7).

Q. DO YOU AGREE THAT INCREMENTAL SOLAR PROVIDES NO CAPACITY VALUE OVER THE 15-YEAR FORECAST PERIOD?

A. No.

Q. WHAT IS THE BASIS FOR YOUR DISAGREEMENT WITH SCE&G ON THE CONTRIBUTION OF SOLAR TOWARD REDUCING CAPACITY COSTS?

A. I continue to have concerns with the simplistic way that SCE&G is modeling the potential capacity contribution of solar generation to the SCE&G system. I believe that SCE&G's recommendation is biased due to the focus on a single winter peak hour, which fails to recognize the outage risks that exist over the rest of the year. SCE&G offers no compelling reasons to assume that new solar installations provide a zero-capacity value. The flaw with witness Lynch's points is the failure to recognize that capacity value is provided not just by output at the time of these historical peaks, but also by the output during the myriad of other peak hours for which there is a non-zero risk of the utility being unable to meet all customer demand. SCE&G employs an overly narrow view of capacity need by focusing solely on the annual winter peak. This deterministic view of planning with a focus on a single peak hour is an outdated approach and poor fit for evaluating emerging issues such as solar capacity contributions.

Q. WHY DO YOU BELIEVE SCE&G'S APPROACH TO CAPACITY VALUATION IS OUTDATED?

A. E3 has been at the forefront of evaluating the impact of renewable resources on utility planning and operations. Through our work it is clear that resources such as wind and solar generation must be evaluated using probabilistic methods that evaluate all hours of a given period, not just a single peak hour. Moreover, the importance of probabilistic models is generally recognized across the industry, as noted by the North American Electric Reliability Corporation's ("NERC") *Probabilistic Adequacy and Measures Technical Reference Report* (April, 2018):

1 There is a recognized need to support probability-based resource adequacy
2 assessment resulting from the changing resource mix with significant
3 increases in variable and energy-limited resources (intermittent in nature),
4 changes in net demand profiles resulting in the shifting of the hour of the
5 peak demand, and other factors can have an effect on resource adequacy.
6 (NERC, p.6)

7 **Q. DID SCE&G PROVIDE A PROBABILISTIC MODEL TO EVALUATE THE**
8 **IMPACT OF SOLAR GENERATION CAPACITY CONTRIBUTIONS? IF SO,**
9 **WHAT DID SCE&G CONCLUDE?**

10 **A.** Yes. SCE&G conducted a Loss of Load Expectation (“LOLE”) study and Witness
11 Lynch provided the results as Exhibit No._(JML-4). Witness Lynch concluded that the
12 probabilistic LOLE method is inferior to SCE&G’s approach “if you are concerned about
13 extreme weather spikes” (Lynch, p. 19).

14 **Q. DID WITNESS LYNCH IDENTIFY A FLAW WITH THE PROBABILISTIC LOLE**
15 **METHOD?**

16 **A.** No. Instead Witness Lynch just demonstrates a fundamental unacceptance of the
17 probabilistic LOLE method and again reaffirms his narrow focus on a deterministic single
18 hour peak. To try to make his point, he shows that if he spikes the load at the time of the
19 peak by 500 MW, then the increased outage risk that this places on the system can be
20 ameliorated by an increase of 195 MW of generation capacity over the entire year. He
21 states that this is an unacceptable increase, implying that 500 MW should be added instead
22 of only 195 MW (Lynch, pp. 18-19).

23 However, it would clearly be overbuilding to add 500 MW of capacity for the
24 chance that you might have a 500 MW spike in load. SCE&G already plans to carry over
25 1,000 MW of capacity in excess of load at the time of their winter peak (based on a 21%
26 winter reserve margin). So, you would only have a problem under the joint conditions that

1 1) you have a spike at the same hour that would have been the peak (spike on any of the
2 other 8,759 hours would not be as bad), 2) you have more than 500 MW of outages from
3 dependable generation, and 3) you have no ability to import power.

4 Probabilistic methods intrinsically consider the joint probabilities of load and
5 generation capacity variations to provide a comprehensive representation of total risk and
6 not “overreact” to deterministic single hour scenarios. Probabilistic methods also correctly
7 recognize that outage risk can exist in hours other than the peak demand hour (because you
8 could have high generation outages in those other hours). Accordingly, it is appropriate to
9 value the capacity contributions of solar generation at the time of the single peak hour as
10 well as during other peak hours that have an outage risk.

11 **Q. HAS SCE&G PROVIDED ADEQUATE INFORMATION REQUIRED TO**
12 **PERFORM A DIRECT CALCULATION OF THE VALUE OF SOLAR OUTPUT**
13 **IN THESE OTHER PEAK HOURS?**

14 **A.** No.

15 **Q. WHAT IS NEEDED TO PERFORM THIS CALCULATION?**

16 **A.** An hourly LOLE study, or similar hourly study, is needed to perform this
17 calculation directly. Unfortunately, the LOLE study performed by SCE&G was only done
18 with daily peak data and is therefore not useful for this calculation.

19 **Q. HOW DO YOU PROPOSE TO CALCULATE THE CAPACITY VALUE OF**
20 **SOLAR, ABSENT AN HOURLY LOLE STUDY FROM SCE&G?**

21 **A.** To calculate the ability of solar to contribute toward avoided capacity costs, I
22 looked to the detailed hourly studies performed by Duke Energy Progress, LLC (“DEP”)
23 and Duke Energy Carolinas, LLC (“DEC”) in their 2018 IRPs filed with the Commission

(Docket Nos. 2018-8-E and 2018-10-E, respectively). Those studies evaluated how the solar contribution to system capacity value changes with differing levels of solar penetration. By comparing the relative amount of solar on SCE&G's system to the findings in those studies, I was able to infer a capacity value contribution for incremental solar on SCE&G's system.

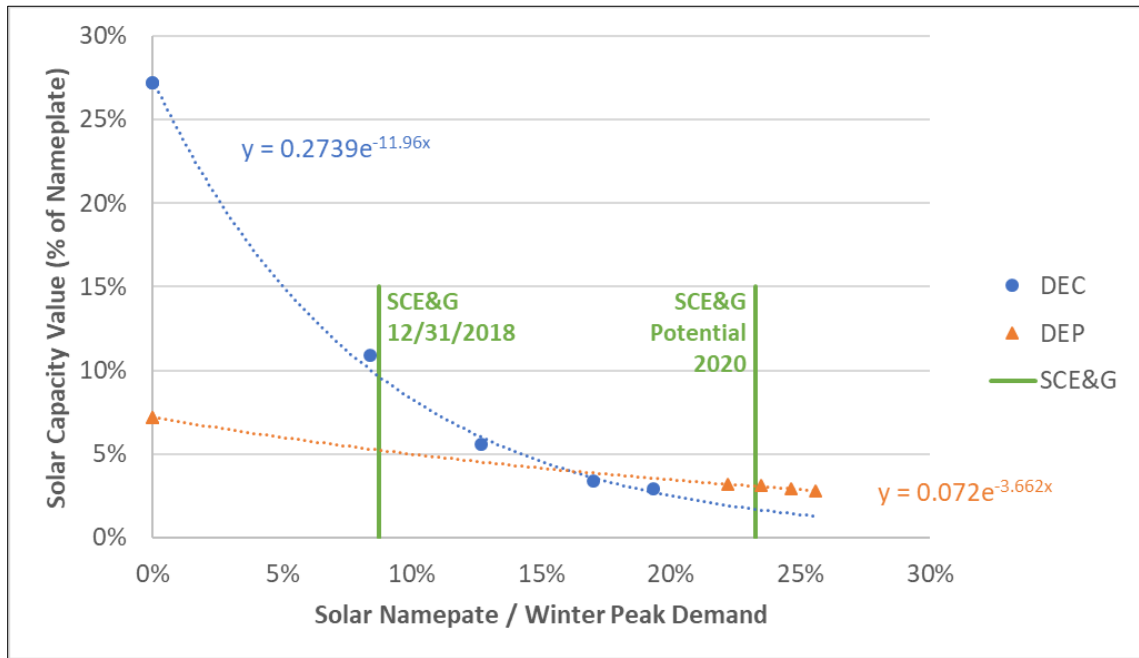
I refer to the capacity value contribution as the "capacity value factor" (the percent of solar nameplate capacity that can be counted toward providing avoided capacity cost value). For example, if solar provided full nameplate output during all hours with an outage risk, the "capacity value factor" would be 100%. Conversely, if solar provided no output during any of the hours with an outage risk, the capacity value factor would be 0%. This capacity value factor is then combined with my estimate of the full avoided cost of capacity for SCE&G to arrive at the avoided capacity value to be used for Rate PR-1, Rate PR-2, and the value of DER.

Q. WHAT INFORMATION DO YOU RELY UPON FOR YOUR ANALYSIS OF THE CAPACITY VALUE FACTOR?

A. DEC and DEP provide detailed capacity value results by solar penetration in their IRP studies. The capacity values are the incremental capacity value of the next MW of solar nameplate, given the referenced solar penetration (DEC IRP, p. 41). This is the same as the capacity value factor I referred to above.

In Figure 1 below, the capacity values for DEC and DEP are plotted against the ratio of the cumulative amount of solar nameplate capacity to the winter peak demand for each utility for 2019. I use this solar-to-demand ratio to normalize for the different utility system sizes.

Figure 1: Capacity Value for Fixed Tilt Solar

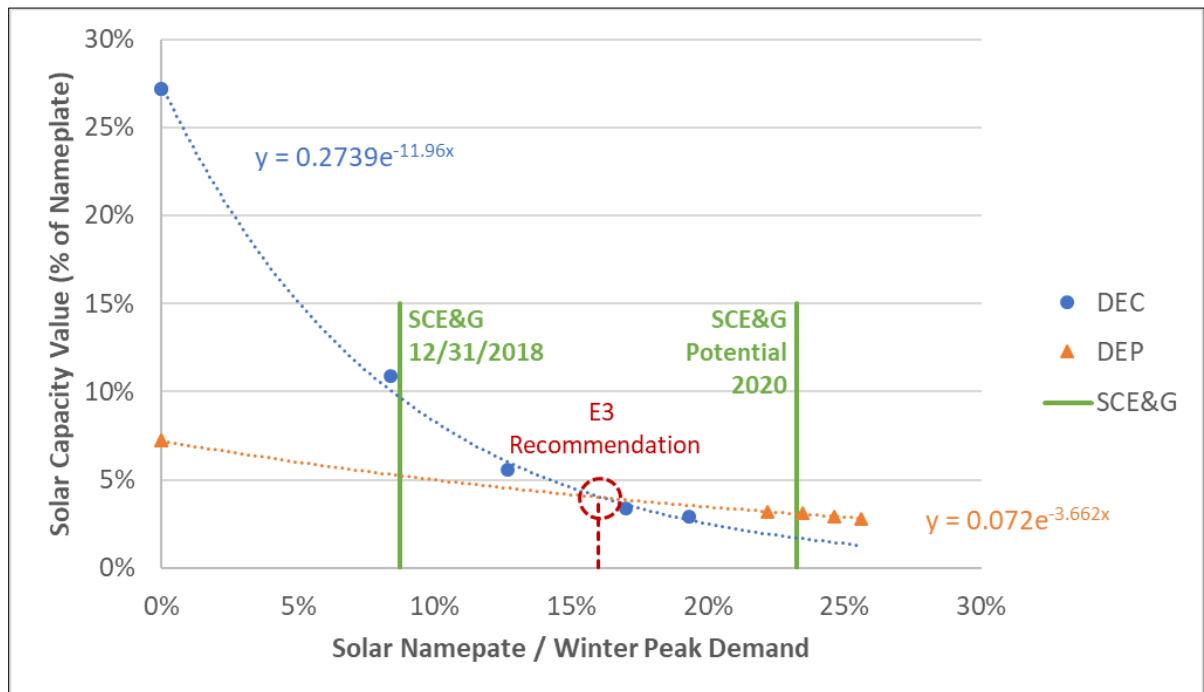


In the figure, the blue dots represent the DEC values and the orange triangles represent the DEP values. Both sets of values fit exponential trends that are shown by the dotted lines, with their equations shown in corresponding colors. The current interconnected SCE&G solar resources totaled 433 MW (Bell, p. 3) in 2018, which is 8.7% of their forecasted 2019 winter peak of 4,964 MW (Lynch, Table 4) and shown on the plot as the left vertical green line. The right vertical green line represents the level of solar SCE&G assumes if an additional 705 MW of solar projects currently under agreement with SCE&G and an additional projected 16 MW of behind-the-meter systems are interconnected by the end of 2020 (Bell, p.4).

Q. WHAT SOLAR CAPACITY VALUE FACTOR DO YOU RECOMMEND FOR SCE&G?

A. Based on the detailed DEC and DEP analyses, and the amount of solar penetration on SCE&G's system, I believe that the figure presents a reasonable range of solar capacity value factors for SCE&G between 3% and 10% for single-axis tracking projects. As it is unknown how many projects will be in-service in the near term, I recommend using the halfway point between the current amount of solar on SCE&G's system and the higher 2020 level projected. This halfway level is shown on Figure 2 as the red dashed line and corresponds to a solar capacity value factor of 4%. This halfway point also has the positive features of 1) reflecting a level of interconnected solar that is slightly above what SCE&G forecasts will be interconnected by the end of 2019,¹ and 2) provides the same solar capacity value factor under both the DEP and DEC formulations.

Figure 2: E3 Recommended Capacity Value Factor



¹ The halfway level equals 794 MW of solar. SCE&G forecasts 643 MW of solar at the end of 2019 (Bell, p. 12).

Q. IS IT APPROPRIATE TO BASE SCE&G'S AVOIDED CAPACITY COSTS ON ANALYSES PERFORMED FOR OTHER UTILITY SYSTEMS? IF SO, WHY?

A. Yes, although it would certainly have been preferable to use an SCE&G-specific study for this analysis. However, the overly simplistic nature of SCE&G's analysis makes it inadequate as a basis for estimating the capacity value that could be provided by incremental solar generation.

Given the close geographic proximity of DEP to SCE&G along with the similarities in peak loads (both have close summer and winter peaks, with recent annual peaks in the winter morning around hour ending 8am) and similarities in conventional resource mixes (both have approximately 40% of their installed capacity from nuclear and coal units), I think it is appropriate to adapt the more rigorous DEP findings on solar performance in South Carolina to SCE&G in this case.

In addition, the similar results using DEC information provides additional confidence in the reasonableness of my recommended value.

Q. WHAT DO YOU RECOMMEND THE COMMISSION ADOPT AS THE AVOIDED CAPACITY PAYMENT FOR RATE PR-1, RATE PR-2, AND THE VALUE OF DER FOR SOLAR PROJECTS?

A. I recommend a solar capacity value of \$0.0029 per kilowatt hour ("kWh") for Rates PR-1 and PR-2 and the 15-year levelized Value of DER.

Q. HOW DID YOU CALCULATE THESE VALUES?

A. These values are based on the marginal capacity cost using the DRR model, the 4% solar capacity value factor, and a 5% performance adjustment factor to reflect an average

1 unavailability of conventional generation resources. The derivation of my recommended
2 value is shown below in Table 1.

3 The marginal capacity cost is based on the revenue requirement model used by
4 SCE&G in 2017 (the last year they provided avoided capacity costs). I updated that model
5 with the following inputs:

- 6 1) Cost of a new advanced combustion turbine (“CT”) from the United States Energy
7 Information Administration (“EIA”) Energy Outlook 2019;
- 8 2) Fixed Operating and Maintenance (“O&M”) costs from the EIA Energy Outlook 2019;
- 9 3) SCE&G’s cost of capital using capital structure and debt cost from September 2018,
10 and the authorized return on equity value of 10.25%;
- 11 4) Federal corporate tax rate of 21%;
- 12 5) Fixed charge rate table for updated rate of return and tax factor; and
- 13 6) Base plan for capacity need using the SCE&G 2019 IRP– Scenario 7.

14 Consistent with SCE&G’s approach in 2017, I added 93 MW CT units starting in
15 the first year that a conventional resource is added in the IRP plan (2029) to hold the reserve
16 margin and the seasonal target (winter 21%). To avoid overbuilding, I supplemented
17 capacity in a year with market purchases if the increment needed was less than 93 MW. I
18 calculated market purchase costs using the \$5.90/kW-month cost (\$2016) used by SCE&G
19 in 2017. I then converted that cost to nominal dollars using an annual inflation rate of 2%.

20 For the change case, I added 93 MW of no cost generation capacity to each year
21 2019 through 2033. I then added generation capacity and market purchases as needed to
22 hold winter reserves at 21%. Note that the additional 93 MW of capacity also allowed me

to eliminate capacity market purchases in 2023 through 2024. I did not, however, sell any excess capacity back to the market.

With these changes, I calculated the annual revenue requirements for capacity for the base and change cases. Over the 15-year analysis period, the change case is \$9.972 million lower in cost per year. Dividing by the 93 MW change in generation capacity results in a 15-year levelized \$107.22/kW-yr. marginal capacity cost. I then converted this marginal capacity cost into a dollar per kWh solar capacity value as shown in Table 1 below.

Table 1: Solar Capacity Value for Rates PR-1 and PR-2 and 15-Year Levelized Value of DER

Line	Item	Value	Source or Calculation
1	2019 Value of Reduced Capacity Need for Capacity in 2029 (\$/kW-yr.)	\$107.22	Differential Revenue Requirement
2	Performance Adjustment Factor	5%	E3 Assumption
3	Adjusted 2019 Capacity Cost (\$/kW-yr.)	\$112.58	L1 * (1+ L2)
4	Solar Capacity Value Factor (Capacity kW/Nameplate kW)	4%	Horii, pp. 13-14
5	Solar Avoided Capacity Cost (\$/Nameplate kW-yr.)	\$4.50	L3 * L4
6	Solar Output per Nameplate kW	1,553	Lynch 2017, p. 24
7	Solar Capacity Value per kWh	\$0.00290	L5/L6

Q. THIS MARGINAL CAPACITY COST SEEMS HIGH SINCE SCE&G DOES NOT ADD A NEW GENERATION RESOURCE UNTIL 2029 IN ITS IRP. CAN YOU RECONCILE THIS?

A. Yes. If we only consider the cost of a new CT in 2029 (or later in the change case), then the marginal cost using the differential revenue requirement method would only be

1 \$78.55/kW-yr. I also calculated the cost of a capacity addition in 2029 using the peak
2 method and arrived at a similar marginal cost value. The SCE&G resource plans, however,
3 show capacity deficits in the base case starting far earlier than 2029 (a small deficit appears
4 in 2022 and increases every year until a resource is added in 2029). While the IRP does not
5 detail how the pre-2029 deficits would be addressed, I believe that market purchases are a
6 reasonable way to quantify those costs. The difference between the \$107.22/kW-yr.
7 marginal cost and the \$78.55/kW-yr. marginal cost is due to the assumed avoidable market
8 purchase costs.

9 **Q. DO YOU HAVE AN OPINION ON SCE&G'S POSITION REQUIRING RATE PR-**
10 **2 NON-SOLAR PROJECTS TO NEGOTIATE THEIR RATES WITH SCE&G**
11 **(NEELY, P. 11)?**

12 **A.** Yes. I believe that SCE&G should provide a standard published rate for such
13 resources. The lack of a published rate increases the uncertainty and engagement costs for
14 new resources. The need to commence a negotiation on compensation terms would increase
15 project lead times and costs for the developers, which could be a significant barrier for such
16 small projects. Moreover, absent the light of a public proceeding, it is unclear whether
17 developers would be disadvantaged in a negotiation and whether SCE&G would be
18 inclined to not reach an agreement so that SCE&G could develop its own resources.

19 **Q. DO YOU AGREE THAT RATE PR-1 NON-SOLAR RESOURCES SHOULD**
20 **RECEIVE NO CAPACITY VALUE?**

21 **A.** No. I believe that it is poor policy to exclude Rate PR-1 non-solar projects from
22 receiving capacity value because of their smaller size. SCE&G denies capacity value to
23 these resources because it “does not foresee that there will ever be enough capacity from

these small non-solar QF's to affect its resource plan" (Neely, pp. 12-13). However, a resource plan is affected by all resources, programs, and customers in aggregate. Therefore, the value of Rate PR-1 non-solar contributions to reducing capacity needs should be valued at the same dollar per kW level as other resources.

Q. DO YOU AGREE THAT INTEGRATING VARIABLE GENERATION RESULTS IN ADDITIONAL COSTS TO UTILITIES?

A. Yes. E3 has conducted extensive work in California and Hawaii where renewable generation comprises a large portion of generation resources. In our own modeling we have seen that increasing amounts of solar and wind generation can require additional ramping capability and reserves to meet both the intermittent nature of solar and wind generation and the diurnal ramping characteristics of solar generation. The cost impact can include higher start-up costs, fuel costs, and O&M costs from operating resources at levels below their maximum efficiency to allow upward headroom to ramp up output. Costs can also increase for additional generation plant required to provide additional flexible capacity.

Q. DO YOU FIND SCE&G'S PROPOSED VARIABLE INTEGRATION CHARGES TO BE A REASONABLE ESTIMATE OF RENEWABLE INTEGRATION COSTS?

A. No. I have reviewed Company witness Tanner's (or "Navigant") Corrected Exhibit No._(MWT-2), Cost of Variable Integration ("Integration Study") and find the overall concepts of the methodology to be reasonable; however, the assumptions used by Navigant unreasonably increase the risks of uncertain variable generation to the Company which inflates the resulting variable integration costs. I propose a more balanced approach which results in a reasonable value for the Variable Integration Charge.

Q. IS IT APPROPRIATE FOR THE UTILITY TO DISPATCH ADDITIONAL RESERVES TO ADDRESS THE POSSIBILITY THAT GENERATION OUTPUT WILL BE LOWER THAN FORECASTED?

A. Yes, the function of operating reserves is to allow the system operator to respond to unexpected changes in generation output or deviations in customer demand. The higher the operating reserves, the lower the risk of having unserved energy. In theory, the level of operating reserves is a balance of the higher cost of providing those reserves with the reduced risk of unserved energy. However, Navigant does not perform any balance of risk and cost in their analysis. Nor do they seek to maintain a specific level of risk previously deemed reasonable. Instead, they assume that solar generation will drop from its forecast level to its minimum output level based on forecast error information from the National Renewable Energy Laboratory (“NREL”). This essentially places an infinite value on the cost of unserved energy, and results in integration costs that are likely higher than what would have been estimated had an actual risk-based analysis been performed.

Q. WHY DO YOU CONSIDER THE INTEGRATION STUDY APPROACH TO BE TOO RISK AVERSE?

A. Navigant states that they model reserve requirements by adding “solar forecast error” to the normal utility reserve requirement. The “solar forecast error” is the maximum drop in output from the aggregate solar fleet, based on the forecasted output of the solar fleet. By using this maximum drop in output, Navigant is estimating the cost of increased reserves based on the assumption that the solar output will be at the lowest level rather than reflecting the actual distribution of potential solar output.

Q. HAS SCE&G PROVIDED THE INFORMATION NECESSARY TO EVALUATE A LESS RISK AVERSE APPROACH TO RESERVES?

A. Yes. The Integration Study (p. 23) is driven by the assumed solar forecast uncertainty from Table 2 below.

Table 2: Navigant Maximum Drop in Generation

Table 9. Solar Forecast Uncertainty	
Expected Generation as % of Installed Nameplate Facility Rating	Maximum Drop in Generation
< 40%	75%
40% - 50%	65%
50% - 55%	45%
> 55%	25%

These values are derived from Navigant's estimates of the probabilities of solar output drops, as reproduced in Table 3 below. Navigant basically looked at a Forecast Generation row and used the Drop value (the column heading) for the furthest left non-zero value on the table. For example, for the 50-55% expected generation level, Navigant used the 45% Drop column shown for the 55% row since that is the leftmost column with a non-zero probability.

Table 3: Navigant Conditional Probability of Solar Variability (circles added)

Table 8. Conditional Probability of Solar Variability								
Forecasted Generation	>75% Drop	>65% Drop	>55% Drop	>45% Drop	>35% Drop	>25% Drop	>15% Drop	>5% Drop
20%	0%	1%	4%	6%	9%	16%	23%	33%
25%	1%	2%	4%	5%	8%	13%	21%	33%
30%	1%	2%	3%	6%	9%	13%	22%	34%
35%	1%	2%	4%	7%	11%	16%	22%	33%
40%	1%	1%	2%	3%	5%	9%	16%	27%
45%	0%	1%	1%	2%	4%	8%	13%	22%
50%	0%	1%	1%	2%	4%	7%	12%	25%
55%	0%	0%	0%	1%	1%	2%	6%	16%
60%	0%	0%	0%	0%	0%	1%	3%	11%
65%	0%	0%	0%	0%	0%	1%	3%	5%
70%	0%	0%	0%	0%	0%	0%	2%	5%

Since SCE&G must maintain self-sufficiency, it is necessary to plan for the worst case drops in solar generation. Table 9 gives the solar generation at risk that is used in this study. In each hour, the amount of solar forecasted to generate is calculated and this table is used to calculate the potential drop in solar that the system may need to respond to.

We can evaluate the effect of SCE&G taking a more balanced approach and exclude the extreme points on the probability distribution. To do that I use that same Table 3 above and move to the right to exclude no more than 2% of the probability of outage for a forecasted generation level. For the 50-55% expected generation level, the solar risk moves from the “>45%” column to the “> 25%” column, as shown in Table 4 below.

Table 4: Navigant Conditional Probability of Solar Variability (with less Risk Aversion)

Table 8. Conditional Probability of Solar Variability								
Forecasted Generation	>75% Drop	>65% Drop	>55% Drop	>45% Drop	>35% Drop	>25% Drop	>15% Drop	>5% Drop
20%	0%	1%	4%	6%	9%	16%	23%	33%
25%	1%	2%	4%	5%	8%	13%	21%	33%
30%	1%	2%	3%	6%	9%	13%	22%	34%
35%	1%	2%	4%	7%	11%	16%	22%	33%
40%	1%	1%	2%	3%	5%	9%	16%	27%
45%	0%	1%	1%	2%	4%	8%	13%	22%
50%	0%	1%	1%	2%	4%	7%	12%	25%
55%	0%	0%	0%	1%	1%	2%	6%	16%
60%	0%	0%	0%	0%	0%	1%	3%	11%
65%	0%	0%	0%	0%	0%	1%	3%	5%
70%	0%	0%	0%	0%	0%	0%	2%	5%

Since SCE&G must maintain self-sufficiency, it is necessary to plan for the worst case drops in solar generation. Table 9 gives the solar generation at risk that is used in this study. In each hour, the amount of solar forecasted to generate is calculated and this table is used to calculate the potential drop in solar that the system may need to respond to.

Repeating the exercise for all four categories of forecasted generation output used by Navigant yields the revisions in Table 5 below. Column C shows the adjusted Drop values, and Column D shows the percentage reduction in forecast uncertainty for each expected generation output category, which equates to a 36.2% weighted average reduction in forecast uncertainty that needs to be addressed with increased reserves.

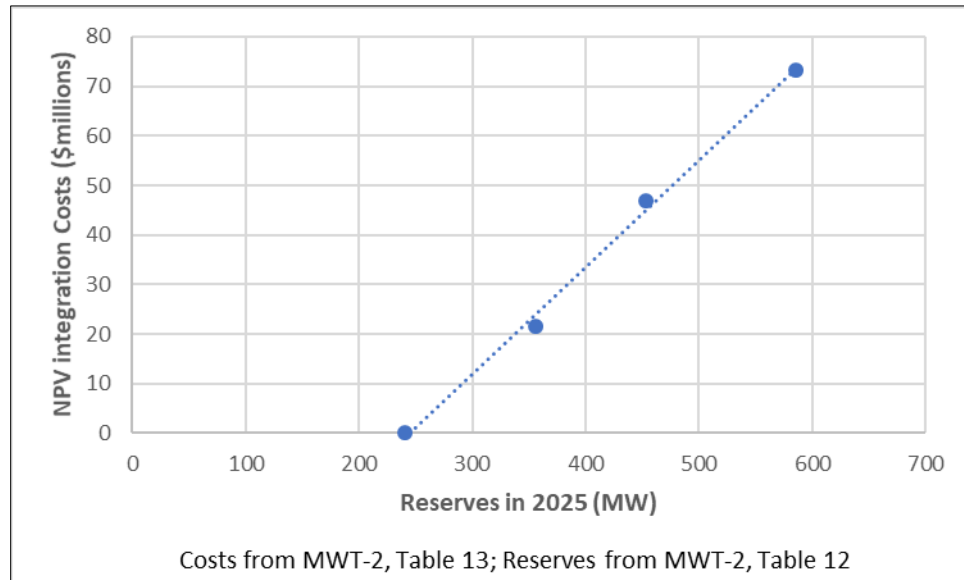
Table 5: Reduction in Incremental Reserve Requirements from Less Risk Aversion

A	B	C	D	E	F
Expected Generation as % of Installed Nameplate Facility Rating	Maximum Drop in Generation	Drop w/o Lowest 2%	% Reduction in Forecast Uncertainty	% Solar Output in Category	Weighted Average Reduction
<i>MWT-2, Table 9</i>	<i>MWT-2, Table 9</i>	Table	$(1-C/B)$	<i>NREL Solar Data</i>	$(Sum\ of\ D * E)$
<40%	75%	55%	26.7%	22%	
40% - 50%	65%	45%	30.8%	15%	
50% - 55%	45%	25%	44.4%	14%	
> 55%	25%	15%	40.0%	48%	
Average					36.2%

Q. HOW DOES THE REDUCTION IN FORECAST UNCERTAINTY TRANSLATE TO A REDUCTION IN INTEGRATION COSTS?

A. The forecast uncertainty drives the amount of additional reserves that Navigant has modeled for SCE&G. Since the forecast uncertainty needed to be covered is 36.2% less than modeled, the amount of additional reserves for solar should also be 36.2% less than estimated. To convert that reserve change to a cost impact, I simply referred to Navigant's estimates of integration costs by reserve level, represented in Figure 3 below. The figure shows that the integration costs can be estimated as a simple linear relationship to additional reserve levels. Because of this linear relationship, the 36.2% reduction in forecast uncertainty results in a 36.2% reduction in integration costs.

Figure 3: Relationship between Reserves and Total Integration Costs



Q. BASED ON THE 36.2% REDUCTION OF INTEGRATION COSTS, WHAT IS THE RESULTING \$/MWH ADJUSTED INTEGRATION COST?

A. SCE&G's proposed integration cost of \$3.96/MWh is really a net integration cost, as it has been reduced by the cost of Energy not Served and Reserves Deficit costs to avoid the double counting of those costs with other values in Rates PR-1 and PR-2 (Tanner, p. 21). To calculate the corresponding adjusted net integration cost, I first calculated the SCE&G gross integration cost by adding back \$0.97/MWh (Tanner, p. 21) to the \$3.96/MWh SCE&G value. I then adjusted the gross integration cost down by my 36.2% and subtracted the \$0.97/MWh value to arrive at a net adjusted integration cost of \$2.18/MWh. These calculations are shown in Table 6 below.

Table 6: Adjusted Net Integration Cost

Line	Item	Value	Source or Formula
1	Navigant Integration Cost (\$/MWh)	3.96	Tanner p. 22
2	Energy Not Served and Reserve Deficit Costs (\$/MWh)	0.97	Tanner, p. 21
3	Unadjusted Gross Integration Cost	4.93	L1 + L2
4	Reduction for Lower Risk Aversion	36.20%	Horii, Table 5
5	Adjusted Total Integration Cost (\$/MWh)	3.15	L3 * (1-L4)
6	Adjusted Net Integration Cost (\$/MWh)	2.18	L5 - L2

Q. YOUR RECOMMENDATION ABOVE IS BASED ON A SIMPLE ADJUSTMENT FOR RISK. HAVE YOU BENCHMARKED YOUR ESTIMATE AGAINST OTHER MORE RIGOROUS ANALYSES?

A. Yes, I compared my adjusted value to the values proposed by DEC and DEP in their 2019 avoided costs docket. The DEC and DEP values are compared to SCE&G's proposal and E3's recommendation in Figure 4 below. As with the prior comparison to DEC and DEP, I used the amount of solar penetration compared to winter peak loads for the x-axis to provide an indication of the relative amount of solar generation on each system. For SCE&G's values I used the amount of solar in 2025, as that is near the midpoint of their analysis.

Figure 4: Renewable Integration Costs Proposed in South Carolina

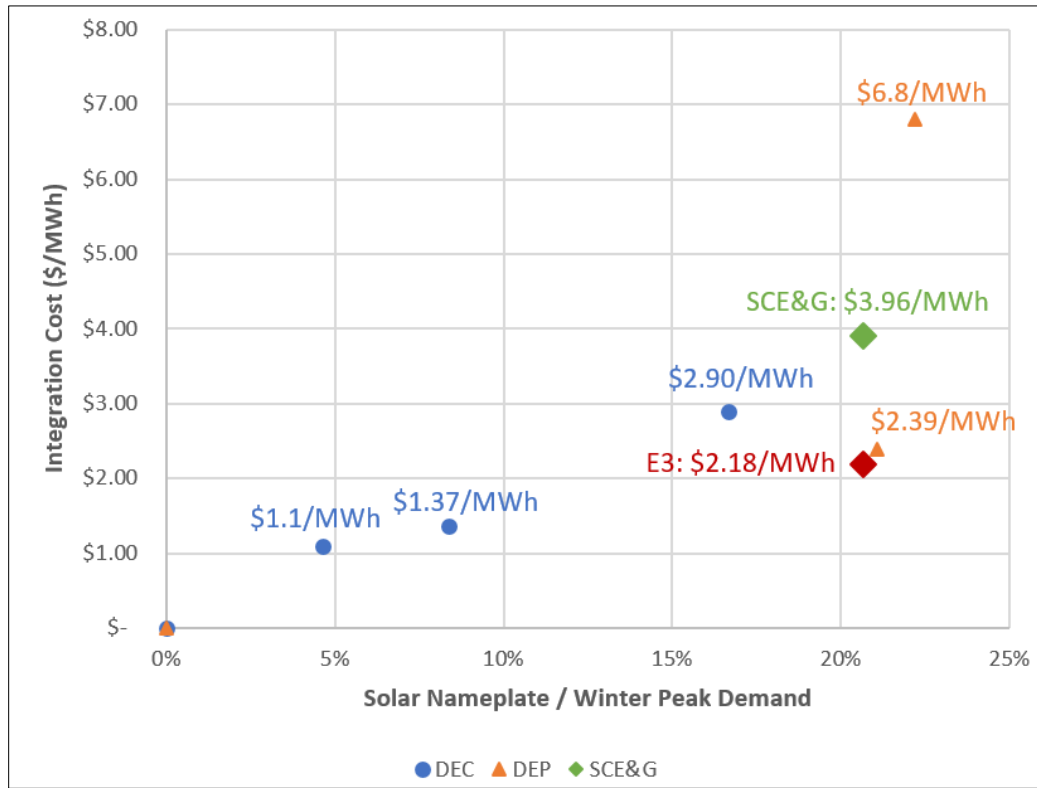


Figure 4 shows that my adjusted integration cost is very close to the value for DEP, and below the highest value for DEC. I believe the DEP result, however, is far more applicable to SCE&G than DEC. DEC has a higher percentage of coal and nuclear generation and lower percentage of natural gas generation than SCE&G and DEP. This would result in less flexibility for DEC and higher integration costs, all other things being equal.

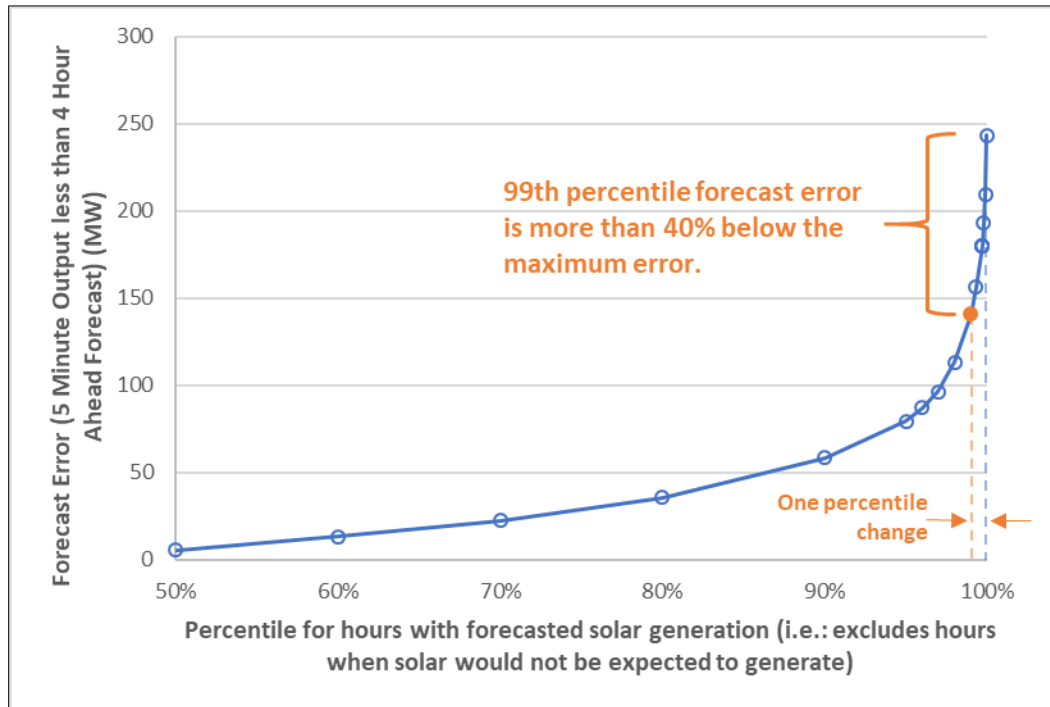
Q. HAVE YOU DONE ANY OTHER ANALYSIS TO EVALUATE THE REASONABLENESS OF YOUR 36.2% REDUCTION IN SCE&G'S PROPOSED INTEGRATION COST?

1 **A.** Yes. My recommendation is to plan operating reserves based on 36.2% less forecast
2 error than Navigant modeled. To assess the reasonableness of using this lower forecast
3 error level, I reviewed the distribution of solar forecast error to determine the percentage
4 of time that forecast error could exceed my recommended level.

5 Using the same NREL dataset as Navigant, I compared the 4 hour-ahead forecasts
6 to the 5-minute actual production data for 4 solar plants located near Beaufort, Charleston,
7 Columbia, and Aiken. The distribution of forecast error is shown in Figure 5 below and
8 displays a dramatic upswing at the right, indicating there are a few hours where the 5-
9 minute solar output is far below the forecasted level. So few hours, in fact, that the 99th
10 percentile forecast error is 40% below the maximum forecast error. As my recommended
11 reduction to Navigant's estimate is only 36.2%, this suggests there is a less than 1% chance
12 that solar forecast error would exceed my recommended level.

13 Given that this less than 1% of hours would only be problematic if there were also
14 the simultaneous problems of lower than expected output from other scheduled generators,
15 limited import ability, and higher than expected customer demand, I believe this is a
16 reasonable balance of risk and costs, especially given my other concern over the Navigant
17 costs being biased upward.

Figure 5: Comparison of Maximum and 99th Percentile Solar Forecast Error



Q. WHAT IS YOUR OTHER CONCERN WITH NAVIGANT’S ANALYSIS?

A. Based on the modeling description in Navigant’s Integration Study, I believe they are overstating reserve needs across the year by holding reserve levels constant throughout each day.

Q. WHY DO YOU BELIEVE NAVIGANT IS HOLDING RESERVES CONSTANT THROUGHOUT THE DAY, AND HOW DOES THIS INFLUENCE THEIR RESULTS?

A. On page 26 of the Integration Study, Navigant acknowledges that “it is important to consider that many individual days within each case have lower forecasted solar than the maximum and hence need fewer reserves.” On page 27 of the Integration Study, Navigant then states that to address this, they ran PROMOD “with each of [three] levels of

1 reserves and then the results were blended using the weighted average of costs tied to the
2 number of days that each level of reserves was required.” [emphasis added] Note that there
3 is no mention of matching reserve requirements to hourly needs, but only matching based
4 on the day.

5 Matching to the day is preferable in assuming the same reserve margin requirement
6 of the entire year, but it is still vastly overestimating the amount of reserves that would
7 need to be carried. For example, why would the higher reserve levels for solar risk need to
8 be carried in the evening or early morning when there is no solar output? Now it could be
9 the case that there is no impact on costs from carrying the unneeded reserves for most
10 hours, but if there are some hours that would have had lower costs with lower reserves,
11 then Navigant’s integration costs would be excessively high. While I cannot quantify the
12 amount of bias, I offer this observation as further support for adopting an integration cost
13 that is below what SCE&G has proposed.

14 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATION FOR THE PROPOSED**
15 **VARIABLE INTEGRATION CHARGES?**

16 **A.** I recommend the Commission adopt my calculated value of \$2.18/MWh as the
17 Variable Integration Charge in SCE&G’s updated PR-1 and PR-2 rate schedules and Value
18 of DER.

19 **Q. PLEASE DESCRIBE CHANGES TO SCE&G'S FILED TOTAL VALUE OF DER.**

20 **A.** As required by Commission Order No. 2015-194, SCE&G must calculate 11
21 components of value for NEM Distributed Energy Resources. In Docket 2018-2-E,
22 SCE&G calculated these 11 components of value; in Order 2018-322(A), the Commission
23 determined the values SCE&G calculated complied with the Methodology as approved by

the Commission in Order No. 2018-322(A). On page 22 of Witness Lynch's direct testimony, SCE&G reports the updated values for these same 11 components.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE AVOIDED CAPACITY COSTS AND UTILITY INTEGRATION AND INTERCONNECTION COSTS COMPONENTS?

A. Based on my analysis and resulting calculations, I recommend updating the components for Avoided Capacity Costs and Utility Integration and Interconnection Costs. Table 7 and Table 8 below summarize the values approved in Order 2018-322(A) in the previous annual fuel proceeding, the proposed values as filed by SCE&G in this Docket, and my recommended values based on my analysis as previously discussed in my testimony. Note that for the current period, I included zero capacity value in my recommendation because SCE&G indicated no need for additional capacity in their 2019 IRP until the year 2022.

Table 7: 15-Yr. Levelized Value of DER (\$/kWh): 2018 Approved and 2019 Filed (Lynch pp. 21, 22), and E3 Recommended

	Approved 2018 (15-yr Levelized)	SCE&G Proposed (15-yr Levelized)	E3 Recommended (15-yr Levelized)	Components
1	\$0.03010	\$0.02339	\$0.02339	Avoided Energy Costs
2	\$0	\$0	\$0.00290	Avoided Capacity Costs
3	\$0	\$0	\$0	Ancillary Services
4	\$0	\$0	\$0	T&D Capacity
5	\$0.00008	\$0.00003	\$0.00003	Avoided Criteria Pollutants
6	\$0	\$0	\$0	Avoided CO ₂ Emission Cost
7	\$0	\$0	\$0	Fuel Hedge
8	\$0	(\$0.00396)	(\$0.00218)	Utility Integration & Interconnection Costs
9	\$0	\$0	\$0	Utility Administration Costs
10	\$0	\$0.00117	\$0.00117	Environmental Costs
11	\$0.03018	\$0.02063	\$0.02531	Subtotal
12	\$0.00246	\$0.00168	\$0.00207	Line Losses @ 0.9245
13	\$0.03264	\$0.02231	\$0.02738	Total Value of DER

Table 8: Current Period Value of DER (\$/kWh): 2018 Approved and 2019 Filed (Lynch pp. 21, 22), and E3 Recommended

	Approved 2018 Current Period	SCE&G Proposed Current Period	E3 Recommended Current Period	Components
1	\$0.03070	\$0.02977	\$0.02977	Avoided Energy Costs
2	\$0	\$0	\$0	Avoided Capacity Costs
3	\$0	\$0	\$0	Ancillary Services
4	\$0	\$0	\$0	T&D Capacity
5	\$0.00008	\$0.00003	\$0.00003	Avoided Criteria Pollutants
6	\$0	\$0	\$0	Avoided CO ₂ Emission Cost
7	\$0	\$0	\$0	Fuel Hedge
8	\$0	(\$0.00396)	(\$0.00218)	Utility Integration & Interconnection Costs
9	\$0	\$0	\$0	Utility Administration Costs
10	\$0	\$0.00113	\$0.00113	Environmental Costs
11	\$0.03078	\$0.02697	\$0.02875	Subtotal
12	\$0.00251	\$0.00220	\$0.00235	Line Losses @ 0.9245
13	\$0.03329	\$0.02917	\$0.03110	Total Value of DER

Q. ARE SCE&G's REASONS FOR WHY IT HAS ZERO VALUE FOR FIVE OF THE OTHER COMPONENTS OF THE DISTRIBUTED ENERGY RESOURCES TOTAL VALUE STACK REASONABLE?

A. Yes. SCE&G is following the methodology approved by the Commission in Order 2015-194 in evaluating the value of each component of the DER's Total Value stack. Regarding Transmission and Distribution ("T&D") Capacity, it should be noted that some jurisdictions recognize the value DER resources can provide in deferring T&D investments and therefore attribute capacity value to resources like solar. SCE&G's practice of designing T&D circuits to assume DER is not generating due to weather factors or because DER resources are off line does follow the Commission approved methodology, but it is a

conservative approach. Regarding avoided carbon dioxide (“CO₂”) emissions, while some jurisdictions recognize value in avoided CO₂ emissions, the Commission directs SCE&G to use zero monetary value for CO₂ emissions “until state or federal laws or regulations result in an avoidable cost on Utility systems for these emissions.” (Order No. 2015-194, p. 9)

Q. WILL YOU UPDATE YOUR TESTIMONY BASED ON INFORMATION THAT BECOMES AVAILABLE?

A. Yes. ORS fully reserves the right to revise its recommendations via supplemental testimony should new information not previously provided by the Company, or other sources, become available.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.



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ENERGY AND ENVIRONMENTAL ECONOMICS, INC.
Senior Partner

San Francisco, CA
1993 – Present

Mr. Horii is one of the founding partners of Energy and Environmental Economics, Inc. (E3). He is a lead in the practice areas of Resource Planning; Energy Efficiency and Demand Response; Cost of Service and Rate Design; and acts as a lead in quantitative methods for the firm. Mr. Horii also works in the Energy and Climate Policy, Distributed Resources and regulatory support practice areas. He has testified and prepared expert testimony for use in regulatory proceedings in California, South Carolina, Texas, Vermont, British Columbia, and Ontario Canada. He designed and implemented numerous computer models used in regulatory proceedings, litigation, utility planning, utility requests for resource additions, and utility operations. His clients include BC Hydro, California Energy Commission, California Public Utilities Commission, Consolidated Edison, El Paso Electric Company, Hawaiian Electric Company, Hydro Quebec, Minnesota Department of Commerce, NYSERDA, Orange and Rockland, PG&E, Sempra, Southern California Edison, South Carolina Office of Regulatory Staff.

Resource Planning:

- Consultant for the CPUC on their Integrated Resource Plan development.
- Evaluated the reserve margin requirements for El Paso Electric using E3's RECAP capacity valuation tool.
- Authored the Locational Net Benefits Analysis tool used by the California IOUs to evaluate the total system and local benefit of distributed energy resources by detailed distribution subareas.
- Created the software used by BC Hydro to evaluate individual bids and portfolios tendered in calls for supplying power to Vancouver Island; demand response from large customers; and new clean power generation.
- Designed the hourly generation dispatch and spinning reserve model used by El Paso Electric to simulate plant operations and determine value-sharing payments.
- Evaluated the sale value of hydroelectric assets in the Western United States.
- Simulated bilateral trading decisions in an open access market; analyzed market segments for micro generation options under unbundled rate scenarios; forecasted stranded asset risk and recovery for North American utilities; and created unbundled rate forecasts.
- Reviewed and revised local area load forecasting methods for PG&E, Puget Sound Energy, and Orange and Rockland Utilities

Energy Efficiency, Demand Response, and Distributed Resources:

- Author of the "E3 Calculator" tool used as the basis for all energy efficiency programs evaluations in California since 2006.
- Independent evaluator for the development of locational avoided costs by the Minnesota electric utilities.

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- Consulted on the development of the NEM 2.0 Calculator for the CPUC Energy Division that was used by stakeholders in the proceeding as the common analytical framework for party positions. Also, authored the model's sections on revenue allocation that forecast customer class rate changes over time, subject to changes in class service costs.
- Coauthor of the avoided cost methodology adopted by the California CPUC for use in distributed energy resource programs since 2005.
- Principal consultant for the California Energy Commission's Title-24 building standards to reflect how the time and area specific value of energy usage reductions and customer-sited photovoltaics and storage.
- Principal investigator for the 1992 EPRI report, Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District, one of the first reports to focus on demand-side alternatives to traditional wires expansion projects.
- Provided testimony to the CPUC on the demand response cost effectiveness framework on behalf of a thermal energy storage corporation.

Cost of Service and Rate Design:

- Designed standard and innovative electric utility rate options for utilities the United States, Canada, and the Middle East.
- Principal author of the Full Value Tariff and Retail Rate Choices report for NYSERDA and the New York Department of Public Staff as part of the New York REV proceeding.
- Developed the rate design models used by BC Hydro and the BCUC for rate design proceedings in 2008, 2010, and ongoing.
- Principal author on marginal costing, ratemaking trends and rate forecasting for the California Energy Commission's investigation into the revision of building performance standards to effect improvements in resource consumption and investment decisions.
- Consulted to the New York State Public Service Commission on the appropriate marginal cost methodologies (including consideration of environmental and customer value of service) and the appropriate cost tests.
- Authored testimony for BC Hydro on Bulk Transmission Incremental Costs (1997). Principal author of B.C. Hydro's System Incremental Cost Study 1994 Update (With Regional Results Appendix).
- Performed detailed market segmentation study for Ontario Hydro under both embedded and marginal costs.
- Testified for the South Carolina Office of Regulatory Staff on SCANA marginal costs.
- Taught courses on customer profitability analysis for the Electric Power Research Institute
- Other work in the area includes marginal cost-based revenue allocation and rate design, estimation of area and time specific marginal costs; incorporation of customer outage costs into planning criteria designing a comprehensive billing and information management system for a major ESP operating in California.

Transmission Planning and Pricing:

- Designed a hydroelectric water management and renewable integration model used to evaluate the need for transmission expansion in the California central valley.
- Developed the quantitative modeling of the net benefits to the California grid of SDG&E's Sunrise Powerlink project. The work was performed in support of the CAISO's testimonies in that proceeding.

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- Testified on behalf of the Vermont Department of Public Service on the need for transmission capacity expansion by VELCO.
- Determined the impact of net vs. gross billing for transmission services on transmission congestion in Ontario and the revenue impact for Ontario Power Generation.
- Authored numerous Local Integrated Resource Planning studies for North American utilities that examine the cost effectiveness of distributed resource alternatives to traditional transmission and distribution expansions and upgrades.
- Developed the cost basis for BC Hydro's wholesale transmission tariffs.
- Provided support to for utility regulatory filings, including testimony writing and other litigation services.

Energy and Climate Policy:

- Author of the E3 "GHG Calculator" tool used by the CPUC and California Energy Commission for evaluation of electricity sector greenhouse gas emissions and tradeoffs.
- Primary architect of long term planning models evaluating the cost and efficiency of carbon reduction strategies and technologies
- Testified before the British Columbia Public Utilities Commission on electric market restructuring.

PACIFIC GAS & ELECTRIC COMPANY

Project Manager, Supervisor of Electric Rates

San Francisco, CA

1987-1993

- Managed and provided technical support to PG&E's investigation into the Distributed Utilities (DU) concept. The projects included an assessment of the potential for DU devices at PG&E, an analysis of the loading patterns on PG&E's 3000 feeders, and formulation of the modeling issues surrounding the integration of Generation, Transmission, and Distribution planning models.
- Served as PG&E's expert witness on revenue allocation and rate design in testimonies before the California Public Utilities Commission (CPUC). Was instrumental in getting PG&E's area-specific loads and costs adopted by the CPUC. and extending their application to cost effectiveness analyses of DSM programs. Additional analytical work included creating interactive negotiation analysis programs, and forecasting electric rates trends for short-term planning.

INDEPENDENT CONSULTING

Consultant

San Francisco, CA

1989-1993

- Helped developed methodology for evaluating the cost-effectiveness of decentralized generation systems for relieving local distribution constraints, and created a model for determining the least cost expansion of local transmission and distribution facilities integrated with area-specific DSM incentive programs.
- Co-authored The Delta Report for PG&E and EPRI which examined the targeting of DSM measures to defer the expansion of local distribution facilities.

Education

Stanford University

Palo Alto, CA

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M.S., Civil Engineering and Environmental Planning

1987

Stanford University

Palo Alto, CA

B.S., Civil Engineering

1986

Citizenship

United States

Refereed Papers

1. Chait, M., B. Horii, R. Orans, CK Woo (2019) "What should a small load serving entity use to hedge its procurement cost risk?" *The Electricity Journal* (2019) 11-14
2. Woo, C.K., I. Horowitz, B. Horii, R. Orans, and J. Zarnikau (2012) "Blowing in the wind: Vanishing payoffs of a tolling agreement for natural-gas-fired generation of electricity in Texas," *The Energy Journal*, 33:1, 207-229.
3. Orans, R., C.K. Woo, B. Horii, M. Chait and A. DeBenedictis (2010) "Electricity Pricing for Conservation and Load Shifting," *Electricity Journal*, 23:3, 7-14.
4. Moore, J., C.K. Woo, B. Horii, S. Price and A. Olson (2010) "Estimating the Option Value of a Non-firm Electricity Tariff," *Energy*, 35, 1609-1614.
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12. Chow, R.F., Horii, B., Orans, R. et. al. (1995), *Local Integrated Resource Planning of a Large Load Supply System*, Canadian Electrical Association.
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18. Orans, R., C.K. Woo and B. Horii (1994), "Targeting Demand Side Management for Electricity Transmission and Distribution Benefits," *Managerial and Decision Economics*, 15, 169-175.

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2. Horii, B., P. Auclair, E. Cutter, and J. Moore (2006) *Local Integrated Resource Planning Study: PG&E's Windsor Area*, Report prepared for PG&E.
3. Horii, B., R. Orans, A. Olsen, S. Price and J Hirsch (2006) *Report on 2006 Update to Avoided Costs and E3 Calculator*, Prepared for the California Public Utilities Commission.
4. Horii, B., (2005) *Joint Utility Report Summarizing Workshops on Avoided Costs Inputs and the E3 Calculator*, Primary author of testimony filed before the California Public Utilities Commission.
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7. Orans, R., C.K. Woo, B. Horii, S. Price, A. Olson, C. Baskette, and J Swisher (2004) *Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs*, Report prepared for the California Public Utilities Commission.

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